SUMMARY OF STUDIES OF SOUTHERN CALIFORNIA INFRASTRUCTURE[1]

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Purpose

In order to assist participants in meetings or discussion of electricity infrastructure issues in Southern California, this brief paper provides an organized comparison of key studies that seem relevant to the long-term planning horizon. [2] Two types of studies are included here: (1) local capacity area studies intended to identify local capacity requirements and by inference suggestive of the amount of once-through cooling (OTC) repowering that must take place given study assumptions; and (2) operating flexibility studies that suggest additional capacity that must be made available to the CAISO Balancing Authority and operated in a manner to satisfy California Independent System Operator's (ISO) identified operating flexibility requirements. Neither of these types of studies have been the focus of analytic work in long-term electricity planning processes until very recently. Only a very limited community of practitioners has access to the models, detailed input assumptions, or detailed results.

Types of Electricity Infrastructure Studies

Several types of studies seem relevant to the topic of replacing San Onofre Nuclear Generating Station (SONGS) and other OTC capacity that will retire as the preferred means of satisfying SWRCB OTC policy. Only two are included here:

1. <u>Local capacity area requirements</u> – local capacity area studies seek to identify the amount of capacity that must be located within a transmission constrained area to assure that 1:10 peak demand can be satisfied when imports into the local capacity area are at the highest level achievable under critical contingency conditions (e.g., under G-1/N-1 or N-1-1 contingency conditions) . The ISO has identified 10 such local capacity areas across its entire balancing authority area, three of which are in Southern California (LA Basin, Ventura/Big Creek, and San

[1] This informal paper was prepared by Energy Commission/Electricity Supply Analysis Division staff to support the *2013 IEPR* workshop held on July 15, 2013 and perhaps other long-term electricity planning forums. It has not been reviewed in the normal manner for an Energy Commission publication.

[2] Given the highly technical methodologies, assumptions, and results related to the various studies described in this brief paper, it is possible that incomplete or even inaccurate descriptions have been made. The authors have made every attempt to avoid doing so.

Diego). Some of these areas also have subareas with even more localized constraints.

2. Operating flexibility studies – the objective of these studies is to determine the amount of flexible capacity required by a system operator to cover the variable production profile of intermittent renewable resources like wind and solar. Flexible capacity is a new concept that has emerged as intermittent resources have reached a substantial penetration of the resource mix. The idea of a net load curve (load curve less the production profile of wind and solar resources) has been developed to represent the pattern of load that dispatchable generators must serve. The dispatchable fleet must be capable of ramping output up and down rapidly and perhaps multiple times per day.

Numerous other types of studies (system stability studies, system supply/demand balances, overall cost minimization studies) are also helpful, but few if any such studies are available.

Studies Relevant to Southern California Infrastructure Assessments

There are six sources of studies that are described in this paper. Four of them address local capacity requirements, while two of them address operating flexibility requirements.

Local Capacity Studies

There are four local capacity studies that are useful in establishing local capacity requirements, and thus influencing the amount of capacity that must be located in local capacity areas.

Study 1: 2012-13 TPP (study complete)

The ISO Board-approved 2012-13 Transmission Plan encompasses a range of objectives, but the studies examining the consequences for local capacity requirements for years 2018 and 2022 with one or both nuclear power plants offline in the context of OTC retirement are most relevant to the questions this paper addresses.

Study 2: 2012-13 TPP High DG Sensitivity (study complete)

The ISO Board-approved 2012-13 TPP included a sensitivity of the impact of higher DG penetration in the LA Basin and San Diego regions on necessary amounts of OTC repowering in the LA Basin. The ISO documents this sensitivity in a brief subsection 3.5.8 of the 2012-2013 Transmission Plan.

Study 3: AB 1318 (studies complete, report in drafting)

ARB's AB 1318 project is designed to satisfy the two-part requirements of the 2009 legislation: (1) identify the capacity additions for SCAB that would require offsets, and (2) determine whether sufficient offsets are available for capacity additions, and if not, identify options for SCAQMD rule changes and/or state legislation. ARB has been pursuing this study in conjunction with the energy agencies identified in the legislation (CEC, CPUC, and ISO). Generally, the project team has identified assumptions to use in the analyses, and then the ISO and LADWP have conducted the studies. Local capacity area requirements and operating flexibility studies have been conducted to identify the aggregate amount of capacity additions that have to be constructed through time out to 2020 and beyond. Since the AB 1318 project began in earnest in 2010, the original studies were based on the 2010 LTPP and the 2011-12 TPP. Once the implications of the SONGS outage were realized in spring/summer 2012, ARB management decided to delay the project to make use of a new round of analyses based on the SONGS outage studies included in the 2012 LTPP and 2012-13 TPP.

Study 4: 2012 LTPP Track 4 (studies complete)

Recognizing that the Track 1 analyses and D.13-02-015 did not address future conditions without SONGS, the CPUC established Track 4 of the 2012 Long-term Procurement Plan (LTPP) rulemaking through an Assigned Commissioner Ruling on May 21, 2013. This ruling provided considerable detail about the demand-side policy impacts and other assumptions that the CPUC wished to be evaluated. In some respects these assumptions are similar to the demand-side policy impacts evaluated in the AB 1318 study. The ISO and CPUC agreed that the ISO would modify its 2012-13 TPP power flow modeling to replace assumptions where the CPUC Ruling specified an alternative value, but all other assumptions would remain the same as used in its own studies. The ISO submitted testimony into the 2012 LTPP Track 4 on August 5, 2013 documenting the results of several cases.

<u>Operating Flexibility Studies</u>

Two studies provide results of analyses of capacity needed for operating flexibility. The two studies are actually variants of a single study, since they were both conducted by the ISO and both generally use assumptions defined by the CPUC in the 2010 LTPP for operating flexibility studies. An additional study of operating flexibility requirements will be published during August 2013 by the ISO as part of CPUC 2012 LTPP Track 2, but its results are not complete at this time.

Study 5: 2010 LTPP Operating Flexibility Studies (studies complete)

As part of the 2010 LTPP proceeding, the ISO prepared and assessed five cases using its deterministic, PLEXOS-based production cost method for determining, given a specific set of resource mix assumptions for year 2020, whether incremental capacity was needed to satisfy operating flexibility requirements.

Study 6: AB 1318 Operating Flexibility Studies (studies complete)

As part of the AB 1318 project team, the ISO used its operating flexibility methodology to assess several minor variations around the assumptions for the base 2010 LTPP cases described as *Study 4*. In these sensitivity case studies, the ISO tested different levels of demand response (DR) and what implications of SONGS retirement would have on top of other OTC-based retirements already assumed in *Study 4*.

Comparison of Local Capacity Assessment Cases

Table 1 summarizes three local capacity analyses from Studies 1-4 so readers can compare input differences and results. Table 1 shows two "sensitivity" cases that are slight departures from the base assumptions of the 2012-13 TPP no SONGS local capacity study for 2022. The first sensitivity – Study 2 – is reported in the 2012-13 Transmission Plan, albeit briefly. The AB1318 sensitivity case has not yet been reported publically, but it seeks to understand how local capacity requirements and generation additions would change given an incremental amount of energy efficiency programs savings and an incremental amount of CHP development compared to the starting case.

For the High DG case, the ISO added DG resources in the LA Basin and in the San Diego area and found the degree to which resource additions would be displaced and still satisfy local capacity requirements. Since the results are reported somewhat sparsely, it is not possible to discern whether OTC repowers, new conventional generation, or some of both are reduced. By adding roughly 1,200 MW (nameplate) of incremental DG, new conventional generation additions were reduced about 500 MW.

For the incremental energy efficiency/CHP/DR case prepared for the AB 1318 project, about 1,582 MW of peak load reduction occurs in the LA Basin and San Diego local areas, but this time the conventional generation additions are reduced about 1,000-1,100 MW in the LA Basin and 100 MW in the San Diego area. The range in generation additions needed is dependent upon the amount of dynamic reactive support modeled. The results show a trade-off between generation and dynamic reactive support. An additional 500 MVAR installed at or near the San Onofre 230 KV switchyard resulted in a 160 MW reduction in generation need in the LA Basin.

Comparison of Operating Flexibility Cases

ISO operating flexibility studies have focused on developing an understanding of additional capacity requirements over and above those required to satisfy other planning standards. How to implement this concept has evolved over the course of the past two years and the studies that have been published. Discussions with the ISO as part of the AB 1318 project suggest that it would be unwise to locate all such additional capacity either north or south of path 26, since that path is sometimes fully loaded. Therefore, it is likely that some portion of any such additions will be targeted for Southern California. Study work to date has not suggested any specific allocation between Northern and Southern California.

Table 2 provides a systematic comparison of eight cases in which the ISO's deterministic, PLEXOS-based operating flexibility methodology was used to determine whether there was a need for incremental capacity solely for operating flexibility purposes.

Counting from the left, Case 1-4 were prepared using CPUC 2010 LTPP input assumptions. Each of these explored a different RPS portfolio. Case 5 was created by the ISO to determine whether increased loads would reveal renewable integration needs. Cases 6-8 were prepared by the ISO as part of the AB 1318 project.

Cases 1-4 modeled the same load of 55,298 MW and incremental energy efficiency/CHP of 6,506 MW and 4,816 MW of supply-side DR, but they each modeled a unique RPS portfolio. The results of these cases show that there are no load following up shortages[3] for any of the RPS portfolios, and there was between 500-600 MW of load following down shortage in both the 33% trajectory base load and 33% environmentally constrained cases. These shortages did not result in any capacity need, because the ISO reasons that power plants can be scheduled offline rather than to follow load down, so none of these cases show any capacity need.

Case 5 was based on the 33% trajectory portfolio as a starting point. The input assumptions were changed to model 10% higher load of 60,828 MW. To satisfy the 33% renewable portfolio standard with higher loads, an additional 1,497 MW of renewable capacity was added to the case. The results of this higher load case show 3,266 MW of load following up and spin shortage and 800 MW load following down shortage. To resolve the shortages, 4,600 MW of generic GT capacity is assumed to be

[3] The Plexos production cost model contains ancillary service requirements for regulation up, regulation down, spinning reserve, non-spinning reserve, load following up, and load following down. If the model is unable to satisfy the requirement, it is recorded as a shortage.

added. The flexibility shortage can be met by different combinations of resources. Generic GT resources were used as a proxy unit to translate shortage into capacity need. Due to minimum capacity and operating constraints, a one megawatt shortage does not translate into one megawatt of capacity need. Generally one would assume that somewhat more actual capacity would have to be added than the shortage itself to account for various real world limitations of specific resources. The ratio between capacity and shortage would likely differ from one technology to another.

Cases 6-8 used Case 5 -- 33% trajectory portfolio/high load -- as a starting point. Case 6 added 3,173 MW of new generation resources in the LA Basin and in the San Diego area as input assumption changes in order to satisfy the projected "need" for local capacity resources in the LA Basin and in the San Diego area.[4] The impact on the operating flexibility study of adding 3,173 MW of modern, flexible generating resources in the LA Basin and San Diego area is to convert the results of the subsequent operating flexibility analysis from a "gross" need to a "net" need for further resources to satisfy operating flexibility requirements. The results of Case 6 show that the 3,173 MW of additional capacity reduced the flexible capacity shortage to 1,251 MW. Results for the capacity need were not reported. When comparing the results of Case 6 to Case 5, adding the assumed local capacity requirements (3,173 MW) with the observed flexible capacity need (1,251 MW) results a total of 4,424 MW, in line with the 4,600 MW need identified in Case 5.

Case 7 is based on Case 6 with DR reduced by 1,961 MW from Case 6 levels. The results of Case 7 show that a 1,961 MW DR reduction increased the flexible capacity shortage by 1,961 MW to 3,212 MW. The DR was modeled as a perfectly flexible resource, so a one MW reduction in DR results in a one MW increase in the shortage of flexible capacity. Load following shortage was not translated into capacity requirements, so capacity is not reported for this case.

Cases 1-7 assume SONGS is online. Case 8 assumes SONGS is offline, but also includes a number of other input assumption changes. In Case 8, demand response is reduced to 826 MW, a reduction of 3,990 MW from the original 4,816 MW level. A higher amount of generating resources are added in order to satisfy the local capacity requirements of the retirement of both fossil OTC plants and SONGS. 5,535 MW is added into the LA Basin and into the San Diego area, which is an increase of 2,362 MW from Case 6 levels. The 5,535 MW local capacity need is based on the CAISO 2012-

[4] The CAISO's 2011-12 TPP 10-year ahead LCR study examined OTC retirements and determined that 3,173 MW of resources had to be developed to replace the lost OTC capacity. For operating flexibility purposes, the CAISO assumed that the following specific resources were added to the Plexos data set: 91) 373 MW combined cycle in San Diego, (2) 1,000 MW of combined cycle in SCE, and (3) 1,800 MW of simple cycle combustion turbines in SCE.

2013 TPP local capacity requirements analyses with SONGS offline for year 2022. The results of Case 8 show a flexible capacity need of 5,300 MW over and above the 5,535 MW added for local capacity purposes and assumed to operate in that manner. Results for the capacity shortages were not reported for this case. Case 8 includes a total of 10,835 MW of new capacity added into the system (5,535 MW of local capacity need + 5,300 MW of flexible capacity need).

References

For each of the five studies described above an internet webpage is cited and pertinent sections of large reports are identified.

Study 1: 2012-13 TPP Local Capacity Studies

Section 3.5 of Chapter 3 addresses the methods and results for years 2018 and 2022 examining the need for capacity additions with SONGS, Diablo Canyon or both facilities offline. Inputs and other assumptions are found in other portions of the report and its seven appendices.

http://www.caiso.com/Documents/BoardApproved2012-2013TransmissionPlan.pdf

Study 2: 2012-13 TPP High DG Sensitivity Study

Building off of the local capacity study methods and results for year 2022, the ISO examined the need for LA Basin capacity additions with SONGS offline and a high level of DG penetration drawn from the High DG portfolio provided by the CPUC/CEC to the ISO. See Section 3.5.8 of the 2012-13 Transmission Plan.

Study 3: 2012 LTPP Track 4 No SONGS LCR Study

The assumptions for demand-side policy impacts and other ley assumptions are found in the May 21, 2013 ACR.

http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M065/K202/65202525.PDF

The results of the ISO's LCR study are found in its testimony filed with the CPUC on August 5, 2013.

http://www.caiso.com/Documents/Aug5_2013_Track_4_Testimony_RobertSparks_R.12-03-014.pdf

Study 4: AB 1318 Project Report

The AB1318 report is still in drafting and review among participating agencies. Some appendices to the AB 1318 report are extracts from other studies that have been published:

- SONGS offline assessment of local capacity requirements for years 2018 and 2022, prepared as Section 3.5 of Chapter 3 of the 2012-13 TPP, was used as the ISO's portion of the "high bookend" analysis in the AB 1318 project. The "high bookend" has no adjustment for demand-reduction policies or the efficacy of using DR programs to satisfy local capacity requirements and/or to contribute towards flexible capacity requirements. All details of this portion of the AB 1318 study have been reported by the ISO. The forthcoming AB 1318 documentation will include Section 3.5 of the 2012-13 Transmission Plan as an appendix. (See above.) The LADWP portion of this analysis was conducted by LADWP using methods comparable to those of the ISO. LADWP's study results have not yet been published in detailed form, but will be part of the forthcoming AB 1318 report.

- The SONGS offline assessment from the 2012-13 TPP was adjusted to examine a low demand sensitivity case study. The ISO used identical power flow modeling inputs except as noted below. This sensitivity can be compared directly to the original 2012-13 TPP results reported by the ISO in the 2012-13 TPP to infer the reduction in local capacity requirements if the demand-side reductions were achieved as assumed.
    - Use of incremental energy efficiency program savings and development of incremental CHP – the AB 1318 project team developed a set of assumptions for higher levels of incremental energy efficiency and incremental CHP.
    - The ISO conducted a sensitivity using starting from its SONGS out power flow cases and reduced loads at busses corresponding to the pattern of incremental energy efficiency load reductions and incremental CHP development identified by the CEC staff. These results will be published as part of the forthcoming AB 1318 report, and details are not available at this time.

- The AB 1318 documentation will provide the results of the original SONGS online assessment of local capacity requirements for year 2021 comparing the OTC repowering requirements with and without incremental energy efficiency program impacts and modest CHP development. These results are documented in an addendum to the ISO's 2011-12 TPP report. This addendum replaces the original Section 3.4 of the ISO adopted 2012 Transmission Plan since errors were discovered in the original analyses.

    http://www.caiso.com/Documents/Addendum-Section3_4_2_1_ISO2011_2012TransmissionPlan.pdf

- Documentation of the impacts of incremental energy efficiency program impacts and a modest level of incremental CHP development is in draft form as an appendix to the forthcoming AB 1318 report.

Study 5: 2010 LTPP Operating Flexibility Studies

The ISO provided an in-depth presentation of their operating flexibility results using 2010 LTPP input assumptions at a May 2011 workshop. To obtain the presentation, use the following webpage and then scroll down to May 2011, then use the hot link to the ISO presentation.

http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/LTPP2010/LTPP_System_Plans.htm

Following its assessment of CPUC-defined cases, the ISO prepared additional cases with loads increased by 10 percent. These results and the previous results are contained in a formal memo from Vice-President Keith Casey to the ISO Board of Directors.

http://www.caiso.com/Documents/110825BriefingonRenewableIntegration-Memo.pdf

Study 6: AB 1318 Operating Flexibility Studies

An initial presentation of the then-current AB 1318 effort was provided in a CPUC 2012 LTPP workshop. Slides 48-57 of the combined CPUC/ISO presentation package from that workshop contain a brief description of cases the ISO prepared in spring-summer 2012. To obtain the presentation, use the following webpage and then scroll down to September 19, 2012, then use the hot link to the presentation.

http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/ltpp_history.htm

Circa Winter 2013, it became clear that SONGS offline needed to be studied. Building on its spring/summer 2012 studies, the ISO prepared a further case that assumes SONGS is offline. Documentation of these results is in draft form as an appendix to the forthcoming AB 1318 report. Some high level results have been provided by the ISO in its presentation to the joint CEC/CPUC workshop held on July 15, 2013.

http://www.energy.ca.gov/2013_energypolicy/documents/2013-07-15_workshop/presentations/06_CAISO_AB1318_7-15-13.pdf

Table 1
SUMMARY OF INPUTS AND RESULTS FOR LOCAL CAPACITY ANALYSES

	Study 1 2012-2013 TPP Base LCR	Study 2 2012-2013 TPP Sensitivity	Study 3 AB1318 Low Bookend Sensitivity	Study 4 2012 LTPP Track 4 w/o SONGs
Modeling				
Study Type	Local Capacity Technical Analyses	Local Capacity Technical Analyses	Local Capacity Technical Analyses	Local Capacity Technical Analyses
Method	Power Flow	Power Flow	Power Flow	Power Flow
Source Study	2012-2013 TPP	2012-2013 TPP	2012-2013 TPP	2012-2013 TPP
Study Year	2022	2022	2022	2022
SONGs	offline	offline	offline	offline
Base Load Forecast	22,917 MW LA Basin;6,056 MW SDG&E	22,917 MW LA Basin; 6,056 MW SDG&E	22,917 MW LA Basin;6,056 MW SDG&E	22,917 MW LA Basin;6,056 MW SDG&E
Load Conditions	Mid-case load, 1-in-10 peak for LA Basin and San Diego LCR areas	Mid-case load, 1-in-10 peak for LA Basin and San Diego LCR areas	Mid-case load, 1-in-10 peak for LA Basin and San Diego LCR areas	Mid-case load, 1-in-10 peak for LA Basin and San Diego LCR areas
Embedded EE (MW)	7985 MW SCE; 1785 MW SD	7985 MW SCE; 1785 MW SD	7985 MW SCE; 1785 MW SD	7985 MW SCE; 1785 MW SD
Policy Adjustments				
Incremental EE (MW)	0	0	973 MW SCE; 187 MW SDG&E	973 MW SCE (746 MW LA Basin); 187 MW SDG&E
Incremental CHP (MW)	0	0	15.1 MW SCE; 0 MW SDG&E	0 MW SCE; 0 MW SDG&E
Fast, Effective DR (MW)	0	0	382 MW SCE; 25 MW SDG&E	173 MW LA Basin; 16 MW SDG&E
Other DR (MW)	0	0	0 MW	794 MW balance of SCE; 203 MW SDG&E
RPS Portfolio	Commercial Interest	High DG	Commercial Interest	Commercial Interest
Renewables > 2012	290 MW LA Basin; 201 MW	178 MW LA Basin; 17 MW	290 MW LA Basin; 201 MW	290 MW LA Basin; 201 MW

	Study 1 2012-2013 TPP Base LCR	Study 2 2012-2013 TPP Sensitivity	Study 3 AB1318 Low Bookend Sensitivity	Study 4 2012 LTPP Track 4 w/o SONGs
	SD	SD	SD	SD
DG (nameplate MW)	431 MW LA Basin; 409 MW San Diego	1,538 MW LA Basin; 490 MW San Diego	431 MW LA Basin; 409 MW San Diego	549 MW LA Basin; 467 MW San Diego
Rooftop Solar PV (statewide installed MW)	0 (2,552 MW embedded in demand forecast)	0 (2,552 MW embedded in demand forecast)	0 (2,552 MW embedded in demand forecast)	219 MW LA Basin; 59 MW SD (2,552 MW embedded in demand forecast)
OTC Retirements (MW) (LA Basin & San Diego)	El Segundo 3, 4 (670 MW); Encina 1, 2, 3, 4, 5 (946 MW); Alamitos 1, 2, 3, 4, 5, 6 (2,011 MW); Huntington Beach 1, 2, 3, 4 (904 MW); Redondo Beach 5, 6, 7, 8 (1,343 MW); SONGs (2,264 MW)	El Segundo 3, 4 (670 MW); Encina 1, 2, 3, 4, 5 (946 MW); Alamitos 1, 2, 3, 4, 5, 6 (2,011 MW); Huntington Beach 1, 2, 3, 4 (904 MW); Redondo Beach 5, 6, 7, 8 (1,343 MW); SONGs (2,264 MW)	El Segundo 3, 4 (670 MW); Encina 1, 2, 3, 4, 5 (946 MW); Alamitos 1, 2, 3, 4, 5, 6 (2,011 MW); Huntington Beach 1, 2, 3, 4 (904 MW); Redondo Beach 5, 6, 7, 8 (1,343 MW); SONGs (2,264 MW)	El Segundo 3, 4 (670 MW); Encina 1, 2, 3, 4, 5 (946 MW); Alamitos 1, 2, 3, 4, 5, 6 (2,011 MW); Huntington Beach 1, 2, 3, 4 (904 MW); Redondo Beach 5, 6, 7, 8 (1,343 MW); SONGs (2,264 MW)
Non-OTC Retirements (MW)	0 LA Basin; 136 MW SD	0 MW LA Basin; 136 MW SD	0 LA Basin; 135 MW SD	0 LA Basin; 135 MW SD
Resource Additions	1920 MW LA Basin; 0 MW SD	Generation under construction	Generation under construction	Generation under construction
Transmission Upgrades	79.2 MVAR capacitor bank at Johanna, Santiago; 2 x 79.2 MVAR capacitor bank at Viejo; reconfigure Barre-Ellis 230 kV lines from 2 to 4 circuits; 230 kV line Sycamore to Penasquitos	79.2 MVAR capacitor bank at Johanna, Santiago; 2 x 79.2 MVAR capacitor bank at Viejo; reconfigure Barre-Ellis 230 kV lines from 2 to 4 circuits; 230 kV line Sycamore to Penasquitos	79.2 MVAR capacitor bank at Johanna, Santiago; 2 x 79.2 MVAR capacitor bank at Viejo; reconfigure Barre-Ellis 230 kV lines from 2 to 4 circuits; 230 kV line Sycamore to Penasquitos	79.2 MVAR capacitor bank at Johanna, Santiago; 2 x 79.2 MVAR capacitor bank at Viejo; reconfigure Barre-Ellis 230 kV lines from 2 to 4 circuits; 230 kV line Sycamore to Penasquitos

	Study 1 2012-2013 TPP Base LCR	Study 2 2012-2013 TPP Sensitivity	Study 3 AB1318 Low Bookend Sensitivity	Study 4 2012 LTPP Track 4 w/o SONGs
Results				
Mitigation Solutions by 2022	Alt. #1, minimize SD Generation	Alt. #1, minimize SD Generation	Alt. #1, minimize SD Generation	Alt. #1, minimize SD Generation
LCR Requirement	11,412-11,712 MW LA Basin, 5,099 MW W LA Basin; 3,100 MW San Diego	not reported	not reported	not reported
OTC Repower	2,900 MW LA Basin; 620-820 MW San Diego	not reported	2,900 MW LA Basin; 520 MW San Diego	2,912 MW LA Basin; 520 MW San Diego
New Generation	1,400-1,700 MW LA Basin; 300 MW San Diego	not reported	400-560 MW LA Basin; 300 MW San Diego	810 MW LA Basin; 400 MW San Diego
Total Repower & New Gen	4,300-4,600 MW LA Basin; 920-1,120 MW San Diego	4,112 MW LA Basin; San Diego not reported	3,300 3,460 MW LA Basin, 820 MW San Diego	3722 MS LA Basin; 920 MW SD
Dynamic Reactive Support	500-1,050 MVAR LA Basin; 960 MVAR San Diego	not reported	500-1,000 MVAR LA Basin; 960 MVAR San Diego	800 MVAR LA Basin; 390 MVAR San Diego
Mitigation Solutions by 2022	Alt. #2, minimize LA Basin generation			Alt. #2, minimize LA Basin generation
LCR Requirement	10,912 MW LA Basin, 5,099 MW W LA Basin; 3,865-4,020 MW San Diego			not reported
OTC Repower	3,820 MW LA Basin; 965 MW San Diego			2462 MW LA Basin; 1085 MW San Diego (modeled as 520 MW from Carlsbad and 585 MW from new fossil gen at SONGS site)
New Generation	920 MW San Diego			560 MW LA Basin; 400 MW San Diego

	Study 1 **2012-2013 TPP Base LCR**	**Study 2** **2012-2013 TPP Sensitivity**	**Study 3** **AB1318 Low Bookend Sensitivity**	**Study 4** **2012 LTPP Track 4 w/o SONGs**
Total Repower & New Gen	3820 MW LA Basin; 1895 MW SD			3022 MW LA Basin; 1485 MW SD
Dynamic Reactive Support	780 MVAR LA Basin; 960 MVAR San Diego			800 MVAR LA Basin; 390 MVAR San Diego

Table 2
SUMMARY OF INPUTS AND RESULTS FOR OPERATING FLEXIBILITY STUDIES

	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8
	33% Trajectory Base Load	**33% Environmentally Constrained**	**33% Cost Constrained**	**33% Time Constrained**	**33% Trajectory High Load**	**AB1318, LCR to Replace OTC Resources**	**AB1318, LCR to Replace OTC and Reduced DR**	**AB1318, SONGs Outage**
Modeling								
Study Type	Operating Flexibility	Operating Flexibility	Operating Flexibility	Operating Flexibility	Operating Flexibility	Operating Flexibility	Operating Flexibility	Operating Flexibility
Method	Production Cost Model, WECC-wide	Production Cost Model, WECC-wide	Production Cost Model, WECC-wide	Production Cost Model, WECC-wide	Production Cost Model, WECC-wide	Production Cost Model, WECC-wide	Production Cost Model, WECC-wide	Production Cost Model, WECC-wide
Source Study	2010 LTPP Plexos model	2010 LTPP Plexos model	2010 LTPP Plexos model	2010 LTPP Plexos model	2010 LTPP Plexos model	2010 LTPP Plexos model	2010 LTPP Plexos model	2010 LTPP Plexos model
Study Year	2020	2020	2020	2020	2020	2020	2020	2020
SONGs	online	online	online	online	online	online	online	offline
Base Load Forecast (2009 CEC-adopted forecast)	55,298 MW, CAISO-system peak	55,298 MW, CAISO-system peak	55,298 MW, CAISO-system peak	55,298 MW, CAISO-system peak	60,828 MW, CAISO-system peak	60,828 MW, CAISO-system peak	60,828 MW, CAISO-system peak	60,828 MW, CAISO-system peak
Load Conditions	Mid-case load, 1-in-2 peak	Mid-case load, 1-in-2 peak	Mid-case load, 1-in-2 peak	Mid-case load, 1-in-2 peak	10 % adder to mid-case load, 1-in-2 peak	10 % adder to mid-case load, 1-in-2 peak	10 % adder to mid-case load, 1-in-2 peak	10 % adder to mid-case load, 1-in-2 peak
Policy Adjustments								
Incremental EE (MW)	5,687 MW	5,687 MW	5,687 MW	5,687 MW	5,687 MW	5,687 MW	5,687 MW	5,687 MW
Incremental CHP (MW)	819 MW	819 MW	819 MW	819 MW	819 MW	819 MW	819 MW	819 MW
Supply-side DR (MW)	4,816 MW (5,145 MW less 329 MW non-event based DR)	4,816 MW (5,145 MW less 329 MW non-event based DR)	4,816 MW (5,145 MW less 329 MW non-event based DR)	4,816 MW (5,145 MW less 329 MW non-event based DR)	4,816 MW (5,145 MW less 329 MW non-event based DR)	4,816 MW (5,145 MW less 329 MW non-event based DR)	2,855 MW	826 MW

	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8
	33% Trajectory Base Load	**33% Environmentally Constrained**	**33% Cost Constrained**	**33% Time Constrained**	**33% Trajectory High Load**	**AB1318, LCR to Replace OTC Resources**	**AB1318, LCR to Replace OTC and Reduced DR**	**AB1318, SONGs Outage**
RPS Portfolio	33% Trajectory Base Load	33% Environmentally Constrained	33% Cost Constrained	33% Time Constrained	33% Trajectory High Load	33% Trajectory High Load	33% Trajectory High Load	33% Trajectory High Load
DG (nameplate MW)	1,052 MW	9,077 MW	1,052 MW	2,322 MW	1,052 MW	1,052 MW	1,052 MW	1,052 MW
Rooftop Solar PV (statewide installed MW)	1,473 MW	1,473 MW	1,473 MW	1,473 MW	1,473 MW	1,473 MW	1,473 MW	1,473 MW
OTC Retirements	All OTC plants (inc. LADWP) retired except SONGs 2-3, Diablo Canyon 1-2, and Moss Landing 1-2	All OTC plants (inc. LADWP) retired except SONGs 2-3, Diablo Canyon 1-2, and Moss Landing 1-2	All OTC plants (inc. LADWP) retired except SONGs 2-3, Diablo Canyon 1-2, and Moss Landing 1-2	All OTC plants (inc. LADWP) retired except SONGs 2-3, Diablo Canyon 1-2, and Moss Landing 1-2	All OTC plants (inc. LADWP) retired except SONGs 2-3, Diablo Canyon 1-2, and Moss Landing 1-2	All OTC plants (inc. LADWP) retired except SONGs 2-3, Diablo Canyon 1-2, and Moss Landing 1-2	All OTC plants (inc. LADWP) retired except SONGs 2-3, Diablo Canyon 1-2, and Moss Landing 1-2	All OTC plants (inc. LADWP) retired except Diablo Canyon 1-2 and Moss Landing 1-2
Resource Additions	Generation under construction	Generation under construction	Generation under construction	Generation under construction	Generation under construction + 1,497 MW more renewables	Generation under construction + 1,497 MW more renewables	Generation under construction + 1,497 MW more renewables	Generation under construction + 1,497 MW more renewables
Resource Additions to Meet LCR Capacity	None	None	None	None	None	2,800 MW SCE, 372 MW SDG&E (3,173 MW total)	2,800 MW SCE, 372 MW SDG&E (3,173 MW total)	4,615 MW SCE, 920 MW SDG&E (5,535 MW total)
Results								
Capacity Shortage	0 MW load following up shortage, 500-600 MW load following	0 MW load following up shortage, 500-600 MW load following down	0 MW load following up/down shortage	0 MW load following up/down shortage	3,266 MW load following up and spin shortage, 800 MW load	1,251 MW	3,212 MW	not reported

	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8
	33% Trajectory Base Load	**33% Environmentally Constrained**	**33% Cost Constrained**	**33% Time Constrained**	**33% Trajectory High Load**	**AB1318, LCR to Replace OTC Resources**	**AB1318, LCR to Replace OTC and Reduced DR**	**AB1318, SONGs Outage**
	down shortage	shortage			following down shortage			
Capacity Need - CAISO system-wide (based on Generic GT)	0	0	0	0	4,600 MW	not reported	not reported	5,300 MW